DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Department of Telecommunications and Energy Investigation into Distributed Generation	**D.T.E. 02-38**

INITIAL COMMENTS OF WYETH BIOPHARMA

I. INTRODUCTION

On June 13, 2002, the Department of Telecommunications and Energy ("Department") on its own motion, opened an investigation into issues relating to distributed generation. Wyeth BioPharma ("Wyeth" or the "Company") hereby offers these comments regarding the Department's investigation. According to the June 13, 2002 order, the Department stated that it intends to focus on three issues during the initial phase of this proceeding:

?? the development of interconnection standards and practices (that do not threaten the reliability or safety of existing distribution systems but also do not present undue barriers to the installation of distributed generation);

?? the appropriate method for the calculation of backup and standby rates and other charges associated with the installation of distributed generation;

?? the appropriate role of distributed generation in distribution company resource planning.

Wyeth has organized its comments in accordance with the outline provided in the Department's June 13, 2002 order and has summarized other issues it feels need to be considered by the Department. A brief summary of the Company's Massachusetts facility has also been provided, along with an Executive Summary. Wyeth believes its perspective as an end-user may help the Department determine what action is needed to encourage (or at a minimum not discourage) investment in distributed generation.

II. EXECUTIVE SUMMARY

Wyeth has made the corporate commitment to environmental and energy stewardship and has actively applied innovative, energy-efficient and environmentally beneficial technologies in its facilities. The Company has recognized the long-term value in energy-efficiency and the benefits associated with capturing and utilizing waste heat through the adoption of co-generation. The adoption and utilization of distributed generation is in the public interest, as viewed by the Commonwealth and the Federal Government, particularly where the technology involves the use of co-generation or utilizes renewable energy sources.[1] The Department has the opportunity to advance the goal of the legislature by: (1) adopting sound policies relative to interconnection requirements; (2) carefully considering the appropriateness and calculation of any backup and standby charges; (3) identifying how the benefits associated with the use of such technologies benefit the Commonwealth and (4) defining how distributed generation could be incorporated into a distribution company's resource planning.

Wyeth acknowledges the complexity of the task before the Department and offers the following recommendations:

?? That the Department recognize the benefits associated with the adoption of distributed generation, including: mitigating transmission system congestion; providing diversity of fuel supply; providing synergies associated with the efficient

[1] General Laws ch. 164, Section 1 (g). *See* generally Title 16 USC 824a.

utilization of energy (e.g. co-generation); and providing significant benefits to the distribution system.

?? That the Department forgo application of backup and standby charges because existing rates adequately compensate the distribution companies for their investment, since they are load factor dependant.

?? If the Department approves backup and standby rates, any imposition should be applied through either: 1) a new separate unbundled rate schedule, which should be reviewed to ensure it does not serve as a disincentive to distributed generation and accurately reflects the true cost of service to the individual customer in question; or 2) through application of a rate rider which does not over-compensate distribution companies for services rendered.

?? Any backup and standby rate structure adopted should be applied on a customer specific basis, where the actual cost of service is factored into the rate.

?? In the event backup and standby charges are assessed, to the extent that customers have invested[2] in distributed generation, these rates should not apply. As to do so amounts to retroactive ratemaking, which is inconsistent with prior practice of the Department and clearly imposes a significant financial burden on customers who have relied on such rates not being applicable. The department should consider application of a distributed generation credit for customers who utilize distributed generation as well as the reduction or elimination of certain demand charge ($/kW) components.

?? The benefits associated with distributed generation should be looked upon as a distribution and transmission system tool, similar to conservation programs.

?? Customers who utilize distributed generation should not be disadvantaged for making investing commitments in distributed generation.

The majority of existing challenges that face distributed generation technology are outside the control of the Department.[3] However, the fair application of rates among customer classes, determination of backup and standby charges, and application of distributed generation incentives is within the purview of the Department. A careful review and application of each of the above-referenced recommendations by the Department can prevent erosion in the

[2] Or made the decision to invest.

application of distributed generation and may provide the financial incentives necessary to sponsor development in the area.

III. BACKGROUND ON WYETH BIOPHARMA AND ITS CURRENT USE OF ON SITE CENERATION

Wyeth (formerly known as "Genetics Institute") has been a part of the Andover, Massachusetts community for more than fifteen years. Genetics Institute was founded in 1980 as an applied research center and soon transitioned to a science-based, product-driven pharmaceutical company developing, manufacturing, and commercializing proprietary drugs.

Wyeth's Massachusett's facilities currently employ more than 2,600 researchers, scientists, engineers, technicians, and other biopharmaceutical professionals and expects this number to grow to 3,000 by the end of 2002. Wyeth is investing more than $2 billion around the world to increase its biopharmaceutical manufacturing capacity, including expanding its Andover Campus. When this project is complete, Wyeth's Andover campus will be one of the largest biopharmaceutical operations in the world.

Wyeth's existing co-generation unit began commercial operation in 1999. Utilizing advanced emission reduction technologies, this generator is not only more efficient but far cleaner than the newest combined cycle gas turbine generators that contribute to the region's power supply. In addition, Wyeth utilizes the steam generated by the unit for its production process. Wyeth continues to investigate the feasibility of using additional sources of on-site

[3] *See* generally Section IV, 4.

generation, and has committed to installing a second unit at its Andover facility, to be in service by the summer of 2003. As an electric customer and an investor in distributed generation, Wyeth is very concerned about the outcome of this proceedings given its potential effect on Wyeth's past and future investments.

IV. CURRENT DISTRIBUTION COMPANY INTERCONNECTION STANDARDS AND PROCEDURES IN MASSACHUSETTS.

A. Standardized Rules and Procedures for the Interconnection of Distributed Generation Must not Shift the Burden from Smaller to Larger Distributed Generation Resources.

Wyeth is an avid supporter of standard interconnection policies, procedures and technical requirements, that maintain a balance between protecting system reliability and safety, while ensuring a process which is not unduly burdensome and a barrier to market entry. Texas, New York and California have seen the value of adopting standards for the interconnection of generators. Wyeth believes that the process can be streamlined without compromising the safe and reliable parallel operation of on-site distributed generation resources. The Maine Public Utilities Commission, in response to a directive from the state's legislature, conducted a study on distributed generation and made recommendations which included developing recommendations on technical interconnection issues for units which are 5MW and smaller, with the added recommendation that the group consider less stringent requirements for units which are less than 100kW. Wyeth acknowledges however that there are site specific interconnection issues, which will also need to be addressed on a case-by-case basis.

Throughout any review undertaken by the Department on this matter, the Department must ensure that any standardization mechanism does not unduly burden customers who install mid to large size generators.[4] As described in greater detail below, the economics associated with utilizing distributed generation are tenuous. Any regulations adopted by the Department should not provide incentives to smaller units, which come at the expense of larger sized units, either through increasing the economic or technical burden on such units. Any such action would amount to cross-subsidization and would be inappropriate. Interconnection incentives provided to smaller units should be accomplished by reducing their technical requirements.

V. CURRENT DISTRIBUTION COMPANY STANDBY SERVICE TARIFFS.

A. <u>Application of Backup and Standby Charges within the Commonwealth Raises Significant Concerns.</u>

1. Independent of Backup and Standby Charges, Distributed Generation Faces Significant Challenges Due to its Generally Higher Capital and Production Costs.

As an initial matter, it is critical for the Department to understand the economic analysis an end-user must make before deciding to invest in distributed generation. Positive factors from an end-user perspective include:

a. the opportunity for waste heat utilization;

b. increased on-site reliability; and

[4] Greater then 1MW.

c. the possible reduction of energy costs.

Negative considerations include:

a. economies of scale (distributed generation typically has significantly higher capital costs per kW than larger supplier-owned generation);

b. higher marginal production costs per kWh as compared to larger units (e.g., higher fuel costs; the need and expense associated with hiring knowledgeable and skilled individuals to maintain a more complex electrical system);

c. potential backup and standby charges;

d. rate structures which may include a significant demand charge;

e. costly interconnection studies and associated interconnection requirements; and

f. air emission standards and the need to comply with Lowest Achievable Emission Reduction (LAER) or Best Available Control Technology (BACT).

As with any financial decision, uncertainty in economic assumptions is undesirable. Electric restructuring has increased this financial uncertainty.[5] For instance, prior to retail access, customers could reasonably anticipate their power cost over a five-year term. Such projections permitted a direct comparison with the costs of an alternative technology, such as distributed generation, with a fairly high confidence level. Today, while the Department's process for approving standard offer and default service rates provides some level of short-term (6 month) stability, customers must undertake their own projections in making longer term, ultimately less reliable assumptions as to market costs for both natural gas and electricity. As with any

[5] "Price volatility in the ISO-NE wholesale market ranged in 2000 from 0.02/kWh to 0.06/kWh…This behavior leaves customers uncertain of the future price of electricity, causing some customers to avoid changing energy sources…" Interim Report on Distributed Generation, Prepared by the Maine Public Utilities Commission, February 2001, p. 10.

economic analysis, it is desirable to have a high level of confidence in the projections utilized. While recognizing that certainty is not possible, it is important for the Department to appreciate the fact the overall level of uncertainty has drastically increased, which provides a further disincentive for investment in distributed generation.

2. The Decision to Install Large Scale Distributed Generation Projects Involves More than Just the Cost of the Generator for an Industrial End-User.

It is important to recognize the differences between smaller scale and mid to larger scale generation options. For example, when evaluating the feasibility of a distributed generator for a mid to larger scale co-generation project, the decision to move forward with a co-generator entails more than the cost of the generator. The need to maximize use of excess steam often results in a decision to install absorption chillers and to forgo the expense of stand-alone boilers that might otherwise be needed in a production process.

Making the investment in distributed generation represents a long-term financial commitment, particularly with respect to the application of co-generation technology.[6] In order to design a co-generation application for a given facility, an engineering feasibility study and final system design which specifies the necessary equipment and their interrelationships, need to be performed. This effort represents a considerable system design change from the equipment and technologies that would otherwise be utilized if the facility had not elected to utilize a co-generator. Imposing backup and standby charges after the fact significantly impacts the long-term economics of operating a facility that utilizes a co-generation unit. Investors in co-generation technologies would be trapped, in that, should the continued operation of the co-generator become uneconomic (through the imposition of backup and standby charges), converting to utility service would require an additional capital investment.[7] It is important for the Department to understand that it is not as simple as disconnecting the co-generator and returning to grid service. From an economic standpoint, not only would the initial investment in the generator be lost, but the further investment in associated conversation costs would be considerable.

3. Once an Opportunity for Installing a Co-generator is Lost, it is Often Permanently Lost.

Once the decision is made not to pursue co-generation, the facility would likely decide to invest in stand-alone boilers to provide process steam and electric chillers. Once these costs are expended, it is significantly less likely that a company would revisit the economics, at least until such time as significant infrastructure replacements or upgrades would be necessary. As such, it is critical for the Department to appreciate the long-term effects its decisions in this proceeding may have on customers within the Commonwealth and their opportunity to evaluate distributed generation.

---

[6] The use of co-generation is ideal in facilities that have the need for both electricity and heat.

[7] I.e. (the purchase and installation of stand-alone boilers, electric chillers, etc.)

4. Third Party Supplier Rates Further Discourage Use of Distributed Generation.

The Department's control of rates is limited to the non-generation portion of the rates. Customers who utilize on-site generation typically have poor load factors.[8] Suppliers of the generation portion of a customer's bill will consider the poor load factor into the customer's pricing, resulting in a less favorable generation service rate than a customer with a high load factor. Currently, the standard offer price provides a temporary buffer to many end-users who utilize distributed generation. Once the transition to a fully competitive market is complete, a customer's load factor will significantly impact the pricing offered by third party suppliers. To the extent it is within its control, the Department must ensure that the combined effect of each distribution companys' unbundled rate components (whether applied via a backup and standby tariff; application of their current rate tariff or the tariff in combination with a rate rider) does not discourage investment in distributed generation.[9] The bulk of the cost associated with serving customers who utilize distributed generation, rests in the generation component. Assuming distribution service rates remain unchanged, once customers are forced to take service through a third party supplier, distributed generation for most customers will be uneconomic.

5. Standard Tariff Rates Alone can Impose Significant Disincentives to the Use of Distributed Generation

[8] This is due to the fact that maintenance outages or unit trips for distribution line disturbances will increase the 15-minute demand for a given month, while the relative energy consumption remains low. In fact, a poor load factor is often an indication of a unit with a high availability factor.

[9] *See* Section V.7, infra.

Rate structures themselves can have a significant impact on the economics of distributed generation and its ultimate financial attractiveness.[10] It is the structure itself, more than the aggregated cost of the energy, that determines the viability of distributed generation alternatives.[11] A volumetric[12] pricing scheme, with a high price per kWh and a lower fixed demand charge ($/kW) is more attractive for distributed generation.[13] In contrast, a rate structure with a high demand charge ($/kW) component can impose a significant financial disincentive by subjecting the customer to a high fixed price ($/kW) demand component.[14]

Exhibits A and B illustrate the financial impact of various rate structures used by distribution companies within the Commonwealth. Exhibit A identifies the majority of Commercial/Industrial rate schedules currently offered by distribution companies and denotes their applicable demand charge ($/kW) component. For exemplary purposes, Exhibit B illustrates, the cost[15] incurred when a customer installs a 5.5 MW generator and the generator goes off line for any reason in a given month. Imposing backup and standby charges which could be in excess of the current tariff charges,[16] in addition to third party supplier pricing that reflects the resulting poor load factor would create an additional disincentive to any form of distributed generation.

---

[10] Distributed Generation Conclusions and Recommendations (Maine Public Utilities Commission Final Report to the Maine Legislature) October 2001, p. 6, 24; Interim Report on Distributed Generation, p. 10.
[11] Interim Report on Distributed Generation Prepared by the Maine Public Utilities Commission, p. 10.
[12] Cents per kWh.
[13] Distributed Generation Conclusions and Recommendations, p. 24.
[14] Id.
[15] Where the cost reflects the total demand charge associated with application of each company's applicable tariff rate, with a 5.5 MW generator.

6. If Distribution Company Rates as Currently in Place Reflect Each Company's Cost of Service, Then no Backup and Standby Charges Should be Imposed.

If the Department believes that each distribution company's current rates reflect the true cost of service then no additional charges or rate structures are necessary. Since under the current unbundled rate structure the load factor of a facility is already considered in the transmission and distribution portion of the rate structure,[17] the distribution company is adequately being compensated for the cost to serve that customer. If the Department does not believe a distribution company's rates reflect their cost of service, then a thorough review by the Department of the individual distribution company's unbundled costs is necessary.

7. Backup and Standby Charges Can be Imposed as a Separate Rate Schedule or Through a Service Rider.

One method of applying backup and standby charges is to apply it to all of a customer's electric usage under a partial requirements rate tariff.[18] Alternatively, a distribution company may utilize a rider that is applied in conjunction with the tariff

---

[16] In its comments, Wyeth has not focused in the rate disparity (between the distribution companies), represented in Exhibits A and B.
[17] For customers with poor load factors, energy costs will be greater under current rates than for customers with higher load factors.

[18] *See*, e.g., Western Massachusetts Electric Company's Rate PR. (Note: Rate is not available to new applicants after September 17, 1999.)

rate that the customer would otherwise take service under. *See* Exhibit C, Central Maine Power-Standby Service Rate.

Regardless of the rate methodology imposed, it is critical that any rate be easy to understand and administer. Simplicity in rate design is critical.

a.) Use of Partial Requirements Rate

Under a rate design where a partial requirements rate is utilized, the customer would no longer take service under the existing tariff rate and would instead take all service under the terms set forth in the partial requirements backup and standby rate tariff. This would be a separate rate, which would apply to all usage at the customer's facility. If the Department utilizes this form of rate design, the rate should stand alone with separate unbundled charge for the distribution, transition, transmission and generation services provided.

a.1) Backup and Standby Charges should be Assessed on a Customer-Specific Basis to Avoid the Potential for Cross-subsidization and to Guard Against Distribution Companies Earning an Unreasonable Return on their Investment.

If the Department determines it is appropriate for distribution companies to adopt backup and standby rates for distributed generation, the rates should be customer-specific for mid to large size generation projects. Any chosen rate should be based on how the project affects the local distribution company. Assessing a system-wide charge or broad-based rate structure on mid to large size units would create cross-subsidization between customers. The number of applications for distributed generation has traditionally been fairly small and is projected to remain low.[19] That being the case, there is an even greater potential for cross-subsidization within a very small class of customers.

In many situations, the customer has already compensated the distribution company for its distribution related expenditures, through a line extension charge or through rates paid over the course of time. In those cases, backup and standby rates would result in an unreasonable return on investment for the distribution company. This is particularly true in situations where the unit is serving new loads. Backup and standby charges that are customer specific would significantly reduce the risk of cross-subsidization.

This newly developed rate should be designed to take into consideration the actual costs associated with supplying service to the individual customer, which means taking into consideration the specific voltage at which the customer receives electric service. Applying an average system charge would not accurately reflect the distribution company's actual costs and should be avoided.

As with the distribution company's current rates, the generation component should reflect the actual cost to provide generation service. As such, whatever price structure is reflected in the distribution company's generation service rate under either standard offer service contract or default service

[19] "Despite improvement and incentives, grid connected generators (including co-generators and distributed generation) that use renewable fuels are projected to remain minor contributors…" Annual Energy Outlook 2002, with projections to 2020.

contract should be reflected in the rate.[20] Distribution and transmission related costs should be reflected in a similar manner.

b.) Use of Rate Rider

The other approach is to apply a rider that operates in conjunction with the otherwise applicable rate which the customer would be served under. Exhibit C illustrates the standby charge applied by Central Maine Power. This rate serves to operate in conjunction with the distribution company's other rates.

When utilizing this rate design methodology, the Department must carefully investigate not only the components of a distribution company's proposed backup and standby rates, but also their interaction with the otherwise applicable tariff rate. Imposing backup and standby charges on a rate structure that already has a moderate to high fixed demand component ($/kW) serves to compound the financial disincentive of utilizing distributed generation. To understand this relationship, it is important to appreciate the fact that like all generators, distributed generation facilities require periodic maintenance outages. These units are also susceptible to distribution line disturbances and will trip off-line due to power quality events on the distribution company's system. In such events, the customer is hit with a demand charge (in 14 out of the 18 rates referenced in Exhibit A), which disproportionately penalizes the customer for the event. See generally Exhibit B.

[20] For example, if default service does not have a demand charge component, neither should the rate. If the distribution company contract has an off or on-peak demand charge component, so too should the generation service rate provided in the distribution company's backup and standby rate.

b.1 If a Rate Rider is Imposed, Backup and Standby Rates Should be Approved in Conjunction with a Restructuring of the Distribution Company's Existing Rate Structure.

Distribution company rates within the Commonwealth are heavily biased toward a fixed rate component resulting in a significant demand charge ($/kWh).[22] A careful review of each distribution company's fixed and marginal costs should be undertaken before or in conjunction with the Department's approval of any backup and standby rate rider to ensure the appropriate level of each distribution company's fixed cost rate components. If backup and standby charges are imposed through a rider which creates an additional financial burden on customers, this review is necessary to avoid over-collection by the distribution companies.

8. Whether Via a Partial Requirements Rate or Rate Rider, Backup and Standby Charges, if Imposed, Should be Volumetric.

In a vertically integrated utility environment, it may have been valid to impose backup and standby rates biased toward a higher demand component ($/kW). However, in an unbundled environment such as in Massachusetts, where the distribution company is no longer responsible for providing generation service and where the regulated (T&D) rates are heavily biased toward the demand component, any additional backup and standby rate applied should be volumetric (cents/kWh). Even without application of additional charges imposed through a backup and standby rate, Wyeth questions the validity of such high fixed cost components.

[22] Wyeth does not know if each distribution company's fixed costs are truly that high, or whether it is the result of how each distribution company attempted to comply with rate reduction requirements of the Massachusetts Restructuring Act.

B. Other Mechanisms Which can be Utilized by the Department to Assist in Mitigating the Current Disincentives Surrounding Investments in Distributed Generation

1. Alternative Rate Structures Should Also be Investigated Which Could Reduce Costs for Distributed Generations.

Exempting distributed generation from application of the transition charge component of a distribution company's rates is one mechanism by which the Department could assist in reducing the negative impact of high fixed ($/kW)

component rate structures. For example, the New Jersey Public Utilities Commission has exempted distributed generation from the applicable competitive transition charge.[23]

To avoid cross-subsidization, Wyeth advocates use of a mechanism which is customer-specific for mid to large size generators. Accordingly, Wyeth suggests the Department consider exempting end-users from the distribution components of a demand charge ($/kW) if the customer has already paid for a line extension or otherwise paid[24] for the distribution facilities to its site. Application of any backup and standby rate structure should be based on the specific circumstances presented. Particularly where new load will be served by the co-generator and a line extension charge has been paid by the customer, the distribution company should not be compensated a second time (through application of a backup and standby charge).

[23] The New Jersey restructuring act specifically required that any plan filed with the Board of Public Utilities not discourage distributed generation. Section 5 of P.L. 1995, c.180 (C.48-2-21.28(11).
[24] As determined in a case-specific review.

Once again, methods and rate structures that may have been warranted when rates were bundled may no longer be applicable with an unbundled rate structure.

2. When Specific Distribution System Limitations Exist, the Customer Should be able to Elect Between Various Service Options.

In certain rare instances, Wyeth sees the potential for infrastructure costs to be significant vis-á-vis anticipated revenues. In those situations, a distribution company's line extension policy should cover the direct costs associated with providing distribution service. However, customers in such situations should be able to elect between:

- ?? paying for distribution related fixed costs via a line extension;
- ?? paying backup and standby rates if no capital contributions toward the line extension were made;
- ?? providing their own backup power;[25]
- ?? electing to forgo backup and standby service, with the distribution company being able to require the customer to install a load-limiting device.

Any of these options would provide sufficient protection to the distribution company without creating a burdensome expense that discourages the utilization of distributed generation.

3. Customers Should not be Subject to Demand Charges that Result from Events on the Distribution Company's Transmission and/or Distribution System.

As noted previously, the demand charge ($/kW) component imposes a

significant

[25]Customers who utilize multiple generators can often provide their own backup service. In a situation where a facility utilizes a series of smaller units, it may be possible to back up loss of one unit. If a customer has the

capability to provide its own backup and standby service through the aggregated use of multiple generators, it should also not be required to pay backup and standby charges.

financial burden on investors in distributed generation. This charge is incurred both for outages caused by the customer's equipment operation (such as maintenance outages) and disturbances on the distribution company's system.[26] These latter events are not under the control of the customer, as such the customer should not be financially responsible for these events. Utilizing the figures set forth in Exhibit B, even without the imposition of backup and standby charges, every month that a 5.5 MW unit were to trip off line, the customer would pay a demand charge of $30,818.48 in Massachusetts Electric Company's ("MECO's") territory (not including the associated kWh charges).[27] If the same facility were located in Western Massachusetts Electric Company's ("WMECO") territory, the demand charge penalty would be 152% of MECO's rate,[28] in Boston Edison Company's ("BECO") territory, the penalty would be 251% of MECO's rate. Again, these charges do not include any possible increase, which may be assigned through application of backup and standby charges. Imposing a backup and standby rate structure that increases the financial burden associated with such events needs to be avoided.

4. Understanding how Current Rates Practically Operate for Distributed Generation will Assist The Department in its Review

It is critical for the Department to understand how the imposition of backup and standby charges will practically operate for the average distributed generation customer.

[26] In many situations these interruptions are caused by distribution and transmission line disturbances on the distribution company's system.
[27] Based on MECO's Rate GS-3, Effective January 1, 2002, which imposes a $3.63 Distribution Demand Charge per kW and a Transition Charge of $1.42 per kW. Calculation based on 5.5MW.
[28] WMECO rate G-2.

Under a volumetric pricing scheme where there is a high cost per kWh and a lower fixed demand charge, the economics for distributed generation are more favorable. In contrast, backup and standby charges with a high customer charge or which subject customers to a high fixed price demand component[29] (even when the average cost per kWh is the same) impose a significant financial burden. A high customer charge in combination with even a moderate demand charge component ($/kW) (in the distribution company's applicable tariff rate) will impose a double penalty on a customer.

VI. THE ROLE OF DISTRIBUTED GENERATION WITH RESPECT TO THE PROVISION OF RELIABLE LEAST-COST DISTRIBUTION SERVICE BY THE MASSACHUSETTS DISTRIBUTION COMPANIES.

A. Adoption and Utilization of Distributed Generation Which Utilizes Co-generation or Renewable Technology is in the Public Good and Should be Encouraged by the Department.

Both the Commonwealth of Massachusetts and the federal government have indicated that the promotion of distributed generation technologies is in the public good. (*See* MGL ch. 164, Section 1(g)j. *See* generally Title 16 U.S.C. 824a). "The Department has recognized the importance of distributed generation as a resource option in the restructured electric industry."[30] The term "distributed generation"[31] encompasses a significant number of

---

[29] *See* generally Id.

[30] Order of Notice citing Competitive Market Initiatives, D.T.E. 01-54, at 11 (2001); see also Qualifying Facilities Rulemaking, D.T.E. 99-38 (1999); Electric Industry Restructuring, D.P.U./D.T.E. 96-100 at 23 (1998).

technologies and resources, from diesel-fired emergency generation[32] to renewable energy projects, co-generation

technologies and combined cycle units (that may or may not utilize available steam production). In addition, distributed generation can come in all different sizes, including small solar powered water heaters to large combustion turbines, each with different availability factors. Factors of size, technology and availability each affect the overall public benefit achieved from the individual units.

Investments in renewable resources and co-generation technologies should be encouraged by the Department. The Department should consider the inherent differences in the technologies and sizes of the facilities. Technologies such as co-generation, which allow for the utilization of waste heat, are critical to encouraging diverse and efficient energy production. [33] [34] Accordingly, the Department should foster continued adoption of such technologies. Technologies that serve to reduce emissions and/or utilize waste steam heat provide a significant public benefit. By comparison, over the past 12 months, Wyeth's emissions associated with its existing unit were between 1.4 to 4.7% of the emissions that would have otherwise been generated from traditional sources.[35]

---

[31] General Laws c. 164, Section 1 defines distributed generation as "a generation facility or renewable energy facility connected directly to distribution facilities or to retail customer facilities which alleviate or avoid transmission or distribution constraints or the installation of new transmission facilities or distribution facilities."

[32] With low availability factors.

[33] "Co-generation of electricity and heat and combined heat and power allow for the productive use of much of the waste heat from electricity production…" National Energy Policy, Report of the National Energy Policy Development Group, May 2001, ch 4, p. 3.

[34] The Malden Mills facility in Lawrence, MA was cited in the National Energy Policy for exceeding 9,500 hours of successful operation and resulting in a reducing emissions, Id pp. 4-9.

[35] This comparison utilized Department of Environmental Protection (DEP) limits for gas, oil and coal fired units. The 1.4% is based on the levels that would have been associated with a unit that meets DEP allowable levels ("an older boiler"). As compared to a coal fired unit which met the latest DEP standards Wyeth's emissions would have been 3.4%.

B. Distribution Companies and Their Customers Benefit from the Investment of Distributed Generation, and its Use Should be Viewed as a Resource Planning Tool.

In a vertically integrated utility market, distributed generation was viewed as a cost to distribution companies. Loss of load was presumed to have a negative impact on the vertically integrated electric company. Today, distribution companies are no longer responsible for providing generation service to customers. In a deregulated market, the advantages of distributed generation from a distribution company's perspective include:

?? decreased system losses;

?? voltage support;

?? balancing support;[36]

?? reduction in transmission system congestion; and

?? reduced need for infrastructure investments.

Utilities historically have argued that the installation of a generator benefits one customer at the expense of others. While certain technical aspects associated with the interconnection may need to be viewed on a site-specific basis, the use of distribution generation should be regarded as a transmission and distribution tool.

Similar to conservation measures, the use of distributed generation needs to be recognized as providing global benefits to the transmission and distribution system and should be recognized as such by the Department and the distribution companies in establishing rates or incentives. The Department recognizes the benefits of conservation efforts, even though they

[36] Interim report, p. 16.

are implemented sporadically across the system. The benefits of distributed generation can be recognized in a similar manner.

C. **<u>The Economic Benefits Associated with the Installation of Distributed Generation from a Transmission and Distribution System Perspective Need to be Factored into any Backup and Standby Charges or Recognized Through a Distributed Generation Credit.</u>**

Given the undisputed economic benefits of distributed generation we recommend the department consider providing a credit to customers whose operations contribute to the reduction of transmission system congestion for the benefit of all ratepayers. Transmission system congestion[37] is a growing issue for certain areas within the Commonwealth. Today, in a deregulated electric environment, generation is dispatched on a bid basis. With loads remaining fixed, the transmission system is forced to absorb the shift from a cost-based dispatch system to a bid-based system. The result is transmission system congestion.[38] In order to minimize transmission system congestion in a manner other than increasing transmission charges to customers in designated congestion zones, it is critical for the electric demand in congested areas to be controlled and/or reduced. Reducing transmission system congestion benefits all customers, that benefit should be credited back in the form of a distributed generation

[37] "A condition of the NEPOOL transmission system in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Following the CMS/MSS effective date, congestion is the condition that results in the congestion component of location being different from the congestion component of the locational price at another location during a given hour of the dispatch day on the day-ahead market and real-time market." Restated NEPOOL Open Access Transmission Tariff FERC Electric Tariff (Fourth Revised), Vol 1 (as amended through the 64th Agreement Amending the New England Power Pool Agreement).

transmission congestion credit to end-users that install distributed generation. The greater Boston area is the most congested area within the New England Power Pool.[39] The locational marginal pricing scheme proposed by the New England Independent System Operator ("NEISO") would increase congestion rates for customers located within the constrained areas.

To the extent that distributed generation assists in reducing congestion, providers of such energy should be compensated through application of a credit. If availability of distributed generation is a concern of the distribution companies, the Department could establish minimum availability factors for these units, in order for them to qualify for any such credit. In transmission-constrained areas, particularly those in the greater Boston area, use of this incentive will likely significantly assist in relieving current congestion problems, and will provide a benefit to customers who have helped reduce congestion by installing distributed generation.

D. The Department Cannot Rely on the Competitive Market to Encourage Development in Distributed Generation.

The NEISO's Load Response Program is one mechanism which parties may claim provides an incentive for distributed generation. In reality, its application falls well short of establishing any long-term incentives. The role of the NEISO is to assume responsibility for the management of New England's electric bulk power generation and transmission systems,

---

[38] Definition of Congestion per NEISO's Restated NEPOOL Open Access Transmission Tariff, FERC Electric Tariff Fourth Revised Vol. 1 (as amended through the 64th Agreement Amending the New England Power Pool Agreement).

[39] "… 85% of the New England congestion uplift … during August - October 2001 occurred in North East Mass/Boston area". NEISO Market Report Quarter 2, FY 2001 (public version) March, 2002, p. 6.

and to administer the region's open access transmission tariff.[40] Guiding principles for the organization include: providing independent, open and fair access to the region's transmission system; establishing a non-discriminatory governance structure; facilitating market-based wholesale electric rates; and ensuring efficient management and reliable operation of the bulk power system.[41]

During times of peak consumption the NEISO has needed to initiate measures to reduce system load in order to maintain the reliable operation of the region's bulk power system. Since its inception, the NEISO has enacted various Load Response Programs to provide incentives for customers to reduce demand during times of peak consumption. While this structure can provide financial incentives to a select number of customers who are able and willing to reduce their consumption, it does not provide an incentive to invest in distributed generation for the following reasons:

?? Customers who utilize distributed generation with high availability factors would likely not be able to participate given the current structure, since their demand is not actually reduced from their base line usage.

?? Load response programs are adopted for a period of one year, and there is no certainty that next year's program will provide similar financial incentives or will remain in place beyond the current year.

If the Department wishes to promote the use of distributed generation, it cannot rely only on the wholesale market to produce the requisite incentives. Electric restructuring was once viewed as a means to remove obstacles to distributed generation.[42] In many ways, restructuring has instead imposed additional limitations on the viability of distributed

---

[40] NEISO Mission Statement.
[41] *See* generally 87th Agreement amending New England Power Pool Agreement, June 21, 2002.
[42] Distributed Generation: The Role of Distributed Generation in Competitive Energy Markets, Onsite Sycom Energy Corporation, (presented to the Distributed Generation Forum) March 1999, p. 12.

generation as a resource. Volatility in the wholesale cost of energy creates significant uncertainty as to the future prices of electricity, making potential distributed generation reluctant to make that commitment.[43]

The NEISO's ability to influence the adoption and promotion of distributed generation is limited, as its authority is limited to the support and maintenance of the regional transmission system. The NEISO has sought to achieve its goals by establishing a congestion management structure that imposes significant charges on certain transmission-constrained areas. While this approach may effectively resolve the issues from the NEISO's perspective, it does so by shifting the financial burden of system limitations to customers in congested areas.

E. Action is Needed by the DTE to Encourage Utilization of Distributed Generation and to Eliminate or Significantly Reduce the Current Barriers to its Use.

None of the Commonwealth's distribution companies have adopted backup and standby rates since the market was restructured in March of 1998. Despite the lack of such rates, the use of distributed generation has not grown significantly. The Energy Information Administration in its 2002 Annual Energy Outlook stated that, despite the adoption of anticipated incentives, it projects a minimal increase in overall energy production from distributed generation facilities. Co-generation is expected to account for the largest portion of this increase.[44] In order for the Department to make a meaningful difference in the level of

---

[43] *See* Interim Report on Distributed Generation February 2001, p. 10. "The wholesale price of competitive energy is unsettled in New England. During 2000, ISO-NE's clearing price generally ranged from 2 cents/kWh to 6 cents/kWh, but experienced periodic spikes as high at $6.00/kWh. This behavior leaves customers uncertain of the future price of electricity, causing some customers to avoid changing energy sources…."

[44] Annual Energy Outlook 2002 (last modified July 8, 2002).

distributed generation developed within the Commonwealth, it will not only need to remedy existing disincentives but provide long term[45] incentives for its adoption and use.

VII. OTHER ISSUES WHICH SHOULD BE CONSIDERED BY THE MASSACHUSETTS DTE.

A. Customers That Invested in Distributed Generation or Made the Commitment to Invest Prior to Adoption of any Backup and Standby Rates Should be Grandfathered.

Since March 1, 1998, backup and standby charges have not been utilized by the Commonwealth's distribution companies. (*See* generally, WMECO, MECO, Fitchburg Gas & Electric and NSTAR's tariffs.) While some distribution companies have reserved the right in the future[46] to impose such charges on new generating facilities, none to Wyeth's knowledge have adopted such rates. Despite this lack of initiative on the part of the distribution companies, customers have needed to make decisions about energy supply options and have been faced with the need to evaluate the benefits and detriments associated with the installation of distributed generation.

The most cost-effective time for any customer to determine whether to move forward with distributed generation or any technology is upon the construction of the system infrastructure.[47] Decisions necessary to run a customer's business can not be put off until distribution companies decide what their policy will be relative to distributed generation.

[45] Any action by the Department must have long term ramifications. Investors in distributed generation will need a comfortable level of certainty that programs and rates will remain in place over a reasonable period of time.
[46] "Reserved" meaning that the distribution company has notified customers that in the future it may impose such a rate.
[47] Associated with a new facility or expansion of an existing facility.
[48] As evidenced by notifying its distribution company as provided in the Department's regulations.

Clearly there is an obligation on the part distribution companies and the Department, not to change the rules in mid-course, particularly if such a change were to result in imposing a burdensome cost on customers. Changing the rules after a customer had made the decision to install such technologies (as well as the associated system infrastructure enhancements which need be to made)[48] would impose a significant and unwarranted burden on customers. Any exemption from backup and standby charges should equally apply to facilities where the decision to invest has already been made. For example, in order to have a unit physically in place even a year from now, decisions and investments[49] need to be made sometimes years ahead of time. Customers need clear direction as to the rates which need to be considered in their economic analysis. It is

inappropriate for the Commonwealth's distribution companies to simply warn that a financially burdensome rate may be applied in the future, when the Customer has no way to estimate the financial impact of such a change.

Today's electric market is filled with considerable uncertainty relative to electric costs. This uncertainty, coupled with the disincentives associated with distributed generation, compounds the problem for end users. Simplifying the rate design and clarifying the scope is essential for customers considering distributed generation.

---

[49] E.g. Electrical and mechanical system designs, including dependant systems such as chillers, boilers, etc. need to be designed, purchased and installed prior to any given co-generator's in-service date.

[50] The Company recognizes that additional protections may be necessary in situations where power is being pushed back into the distribution system, and Wyeth suggests that those situations be considered separately by the Department.

CONCLUSION

The Department has recognized by opening this proceeding that there are benefits which should be considered and weighed in evaluating distributed generation. For the reasons noted above, the economics of utilizing co-generation are tenuous at best. Wyeth urges the Department to carefully consider the financial ramifications of any decision made relative to the imposition of backup and standby rates. The current rate structure adopted by distribution companies serves to discourage investment in distributed generation due to its significant demand charge ($/kW) component. As such, no additional charges should be applied to customers who utilize distributed generation to reduce electric consumption at their facilities.[50] Not being able to factor the effect of charges that are greater than what is presently incorporated in a distribution companys tariff rates, places an unnecessary and undue burden on the end-user.

As previously noted, there is considerable justification to question the validity of backup and standby charges in a competitive marketplace, however, should the Department deem it appropriate to approve such rates: 1) their application should not be retroactive and should not be applied to any customer who has previously installed or committed to install distributed generation; 2) any rate structure imposed needs to be customer specific to avoid cross-subsidization; 3) the rate should not increase[51] energy costs to customers; 4) the rate should reflect the actual cost to serve.

---

[51] Beyond what they currently pay today.

The benefits provided to all ratepayers through the reduction of transmission system congestion and distribution related costs should be passed onto users of distributed generation. Mechanisms which could be utilized for this purpose, include: 1) a distributed generation credit; 2) reducing the distribution demand charge ($/kW); and 3) eliminating the transition service charge component, that would otherwise be applicable. In order for any incentive to be effective, it must provide a long-term incentive.

Wyeth's co-generation facility has demonstrated an efficiency of 80%. As an environmentally conscious corporation, Wyeth has committed itself to environmental and energy stewardship and has made significant financial investments based on this commitment. Wyeth and similarly situated customers should not be disadvantaged for making these commitments. Wyeth urges the Department to recognize the value for energy related investments that serve the public good, for the benefit of both rate payers and the public at large.

The true challenge which will eventually face distributed generation, will be how it effectively competes in a market where the generation component is priced solely based on load factor. Once the protection offered by standard offer service is permanently lost, the combined cost of generation service plus distribution service (with a high demand charge component), will significantly discourage distributed generation. Like many other industrial customers, Wyeth's process and reliability needs, make it an ideal candidate co-generation. If the economics do not work for a company such as Wyeth, they will not work for other customers.

Wyeth thanks the Department for the opportunity to provide comments on this investigation. The Company is hopeful that an end user perspective assists the Department in its review. As a large power customer that has invested in distributed generation resources, Wyeth has a significant interest in the outcome of these proceedings and is pleased for the opportunity to comment.

RESPECTFULLY SUBMITTED,

Wyeth BioPharma,
By its Attorney

____

Lisa M. Barton, Esq.
Ransmeier and Spellman P.C.
One Capitol Street
Concord, NH 03301
Email lbarton@ranspell.com
(603) 228-0477 ext. 258
(603) 224-2780

262495